OAR-2002-0059
II-A-11

EPA/310-R-99-006.

EPA Office of Compliance Sector Notebook Project

Profile of the Oil and Gas Extraction Industry

October 1999

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Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
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II. INTRODUCTION TO THE OIL AND GAS EXTRACTION INDUSTRY

This section provides background information on the size, geographic distribution, employment, production, sales, and economic condition of the oil and gas extraction industry. Facilities described within the document are described in terms of their Standard Industrial Classification (SIC) codes.

II.A. Introduction, Background, and Scope of the Notebook

This industry sector profile provides an overview of the oil and gas industry as listed under SIC code 13. The SIC code 13 encompasses the oil and gas extraction process from the exploration for petroleum deposits up until the transportation of the product from the production site. There are five major groups within SIC code 13:

SIC 1311. Crude petroleum and natural gas. Establishments in this industry are primarily involved in the operation of oil and gas field properties. Establishments under this category might also perform exploration for crude oil and natural gas, drill and complete wells, and separate the crude oil and natural gas components from the natural gas liquids and produced fluids.

SIC 1321. Natural gas liquids. This industry is comprised of establishments that separate natural gas liquids from crude oil and natural gas at the site of production. Examples of these gases are propane and butane. Natural gas liquids producers that remove additional material at petroleum refineries are classified under SIC code 29, and establishments that recover other salable contaminants such as helium are classified under SIC code 28.

SIC 1381. Drilling oil and gas wells. This industry is made up of establishments that drill wells on a contract or fee basis.

SIC 1382. Oil and gas field exploration services. Establishments in this industry perform geological, geophysical and other exploration services for oil and gas on a contract or fee basis.

SIC 1389. Oil and gas field services, not elsewhere classified (NEC). Establishments in this industry perform services on a contract or fee basis that are not elsewhere classified. These include the preparation of drilling sites by building foundations and excavating pits, the completion of wells and preparation for production, and the performing of maintenance.

While this notebook covers all of the SIC codes listed above, the diverse nature of the industries will not allow a detailed description of each. Since the service industries (SIC codes 1381, 1382, and 1389) and natural gas liquids industry (SIC code 1321) are tied to the economic, geographic, and production trends of SIC code 1311, most attention is focused on the crude petroleum and natural gas industry. Although certain products under these SIC codes may not be specifically mentioned, the sector-wide economic, pollutant output, and enforcement and compliance data in this notebook covers all establishments involved with oil and gas extraction.

SIC codes were established by the Office of Management and Budget (OMB) to track the flow of goods and services within the economy. OMB is in the process of changing the SIC code system to a system based on similar production processes called the North American Industrial Classification System (NAICS). In the NAICS, the SIC codes for the oil and gas extraction industry correspond to the following NAICS codes:

1987 SIC	U.S. SIC Description	1997 NAICS	NAICS Description
1311	Crude Petroleum and Natural Gas	211111	Crude Petroleum and Natural Gas Extraction
1321	Natural Gas Liquids	211112	Natural Gas Liquid Extraction
1381	Drilling Oil and Gas Wells	213111	Drilling Oil and Gas Wells
1382	Oil and Gas Field Exploration Services	54136	Geophysical Surveying and Mapping Services
		213112	Support Activities for Oil and Gas Operations
1389	Oil and Gas Field Services, NEC	213112	Support Activities for Oil and Gas Operations

II.B. Characterization of the Oil and Gas Extraction Industry

II.B.1. Product Characterization

The primary products of the industry are crude oil, natural gas liquids, and natural gas. Crude oil is a mixture of many different hydrocarbon compounds that must be processed to produce a wide range of products. U.S. refinery processing of crude oil yields, on average, motor gasoline (approximately 40 percent), diesel fuel and home heating oil (20 percent), jet fuels (10 percent), waxes, asphalts and other nonfuel products (5 percent), feedstocks for the petrochemical industry (3 percent), and other lesser components (U.S.

Department of Energy, Energy Information Administration (EIA), 1999). Volumes of oil and refined products typically are reported in barrels (bbl), which are equal to 42 gallons.

When crude oil is first brought to the surface, it may contain~~ed~~ in a mixture of natural gas and produced fluids such as salt water and both dissolved and suspended solids. On land (and at many offshore operations) Natural gas is separated at the well site and is processed for sale if natural gas pipelines (or other transportation vehicles) are nearby, or is flared as a waste (at onshore operations only). Water (which can be more than 90 percent of the fluid extracted in older wells) is separated out, as are solids. Only about one-third of the production platforms offshore in the Gulf of Mexico separate water. The other offshore Gulf platforms transport full well stream, sometimes great distances, to central processing facilities. The crude oil is at least 98 percent free of solids after it passes through this onsite treatment and is prepared for shipment to storage facilities and ultimately refineries (Sittig, 1978).

Natural gas can be produced from oil wells (called *associated gas*), or wells can be drilled with natural gas as the primary objective (called *non-associated gas*). Methane is the predominant component of natural gas (approximately 85 percent), but ethane (10 percent), propane, and butane are also significant components. The heavier components, including propane and butane, exist as liquids when cooled and compressed; these are often separated and processed as natural gas liquids.

Less frequently, oil and gas can be produced by other methods. Oil can be found in tar sands, which are porous rock (sandstone) structures on the surface to 100 meters deep. The material is fairly viscous, and also is fairly high in sulfur and metals. Although the Athabasca region in Canada is the primary area of significant tar sand mining, there are some deposits in the western United States.

Oil may also be extracted from oil shale. These deposits may be 10 to 800 feet below the surface, and can be removed by surface mining or subsurface excavation. The oil, in a highly viscous form called *kerogen*, is usually heated to allow it to flow. Because only approximately 30 gallons (less than a barrel) are produced per ton of shale, the process is costly, and the oil shale mining industry is currently only a minor contribution to the domestic oil supply.

A small but increasingly significant source of natural gas is coalbed methane. In all coal deposits, methane is found as a byproduct of the coalification process and is loosely bound to coal surface areas. This methane historically was considered a safety hazard in the coal mining process and was vented, but recently it has been recovered in conjunction with mining or produced independently via wells in deposits that are too deep for mining. Generally, coalbed methane is collected by drilling a well similar to those used for conventional oil and gas deposits, but with some adaptations to accommodate mining operations and different rock characteristics (EPA, 1992). In 1997, coalbed methane production accounted for six percent of the total U.S. natural gas production (EIA, 1998).

Methane hydrates are another form of natural gas, for which economically viable recovery methods are still in development. Methane hydrates are structures in which methane molecules are trapped within a lattice of ice. They are found principally in cold and/or pressurized conditions: on land in permafrost regions, or beneath the ocean at depths greater than 1,500 feet below the water surface. These eventually could be an immense resource; estimated amounts of methane in these structures in the United States is 200,000 trillion cubic feet, compared to an estimated 1,400 trillion cubic feet in conventional natural gas deposits. A goal of the U.S. Department of Energy methane hydrates research program is to develop a commercial production system by the year 2015 (U.S. DOE, 1998).

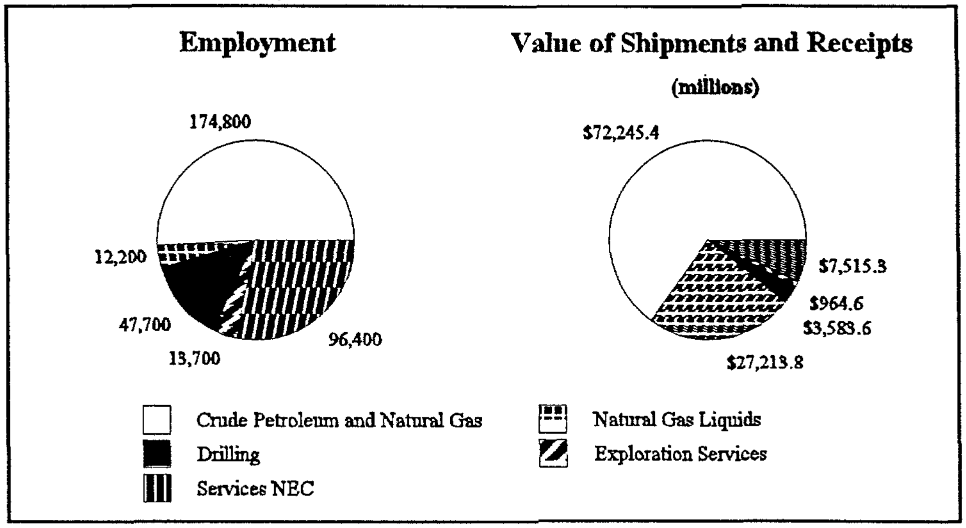
II.B.2. Industry Size and Distribution

The oil and gas extraction industry is an important link in the energy supply of the United States. Petroleum and natural gas supply 65 percent of the energy consumed in the United States, and domestic producers supply approximately 40 percent of the petroleum and 90 percent of the natural gas (EIA and Independent Petroleum Association of America (IPAA), 1999). According to the 1992 Census of Mining Industries, the industry employed 345,000 people and had yearly revenues of $112 billion.

Several factors influence the size of the industry, including technology development and crude oil prices (which are set in world markets) (EIA, 1999). Employment in the industry is also affected by the recent trend in mergers and consolidation among companies in the industry.

Within the overall oil and gas extraction industry group (SIC code 13), SIC 1311 (crude petroleum and natural gas) is the largest. As shown in Figure 1, this industry employs half of the total workers in this SIC group, and accounts for about 60 percent of the sales. SIC code 1389 (services not elsewhere classified) is the next largest employer, but SIC code 1321 (natural gas liquids) is more significant with respect to sales.

Figure 1: Employment and Value of Shipments and Receipts in the Oil and Gas Industry



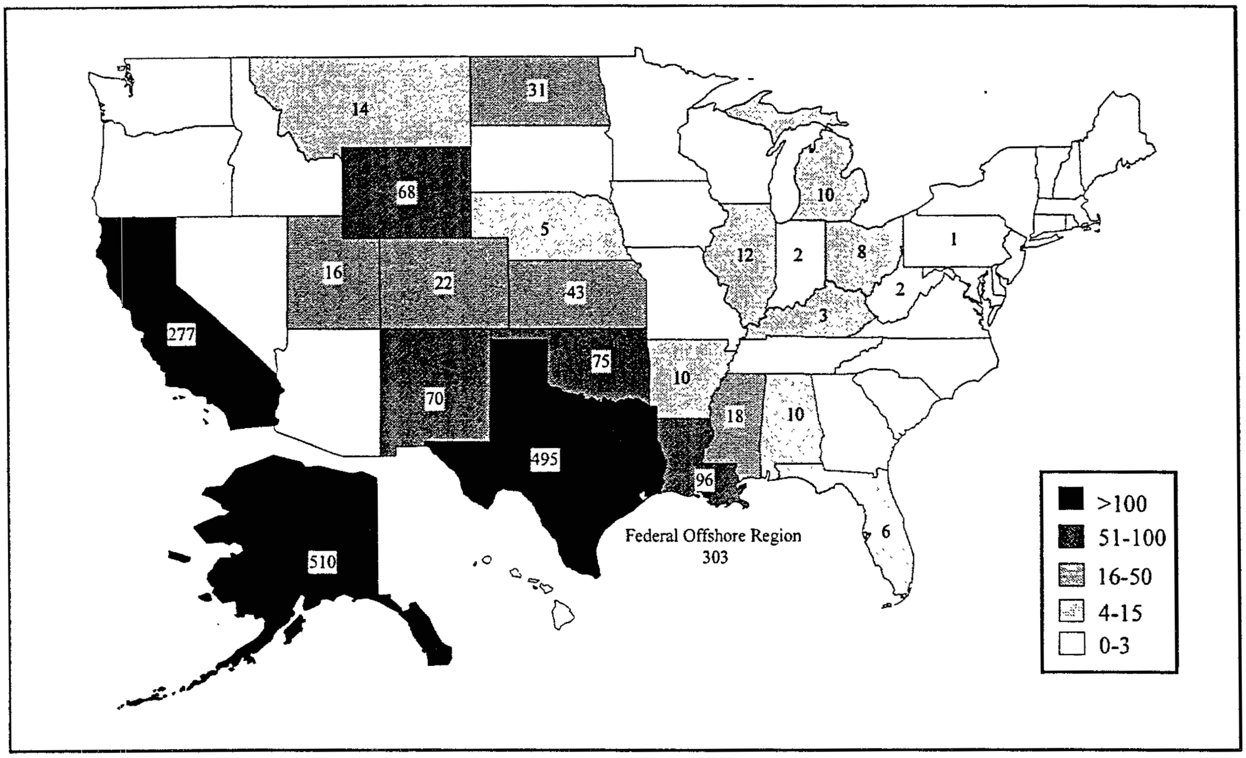
Source: *1992 Census of Mineral Industries,* U.S. Department of Commerce, 1995.

The major oil- and gas-producing areas in the United States are in the Gulf of Mexico region (onshore and offshore), California, and Alaska (see Figure 2). The Gulf of Mexico and surrounding land in particular is the most concentrated area of production; in 1998, Texas (onshore and offshore) produced 23 percent of the nation's crude oil, Louisiana produced 5 percent, and 14 percent was produced in the Federal offshore region.[1]

The geographic distribution is similar for natural gas; Texas, Louisiana, and the Gulf of Mexico are the major producing locations (Figure 3). New Mexico, Oklahoma, Wyoming, and Kansas are also important gas-producing states, while California and Alaska are less important with respect to natural gas production than they are for crude oil.

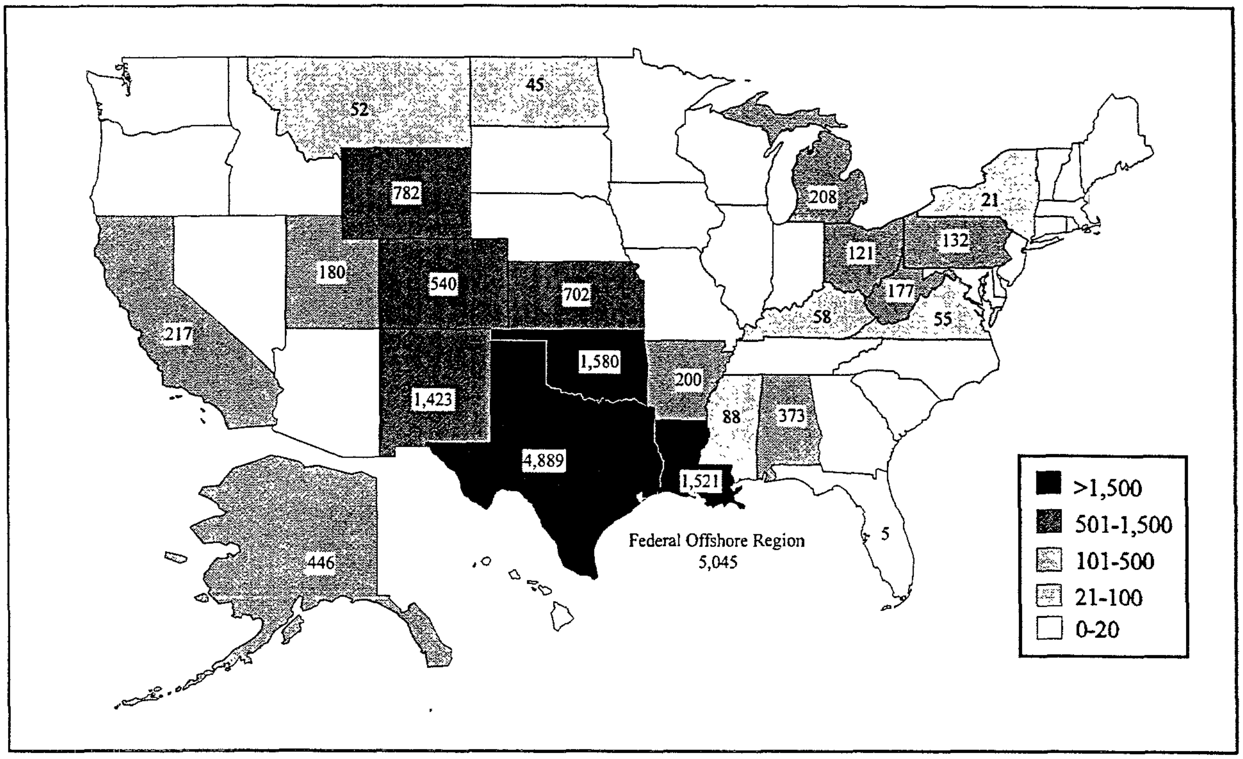
[1] The Federal Offshore Region, or Outer Continental Shelf (OCS), is seaward of State jurisdiction (3 nautical miles, or approximately 3.3 statute miles, from an established baseline except for Texas and the Gulf coast of Florida, for which the boundary is 3 marine leagues, or approximately 10 statute miles), and landward of a line defined by international law at a minimum of 200 nautical miles (MMS, 1997) (See p101 for more details).

Figure 2: 1996 U.S. Crude Oil Production (Million Barrels per Year)



Note: Small quantities are also produced in Arizona, Missouri, Nevada, New York, South Dakota, Tennessee, and Virginia.
Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1996 Annual Report*, EIA, 1997.

Figure 3: 1996 U.S. Natural Gas Production (Billion Cubic Feet per Year)



Note: Small quantities are also produced in Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, South Dakota, and Tennessee.
Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1996 Annual Report*, EIA, 1997.

The oil and gas industry has a unique standing for census purposes because of the sheer number of wells in the country. For the purposes of simplifying reporting procedures under SIC code 1311, the census defines an establishment as all activities of an operating company in an entire state. Therefore, these data give no information on the number of individual wells. Data collected by the Independent Petroleum Association of America, however, indicated that in 1997 there were 573,504 active wells extracting primarily crude oil, and 303,724 wells producing primarily natural gas in the United States (IPAA, 1999).

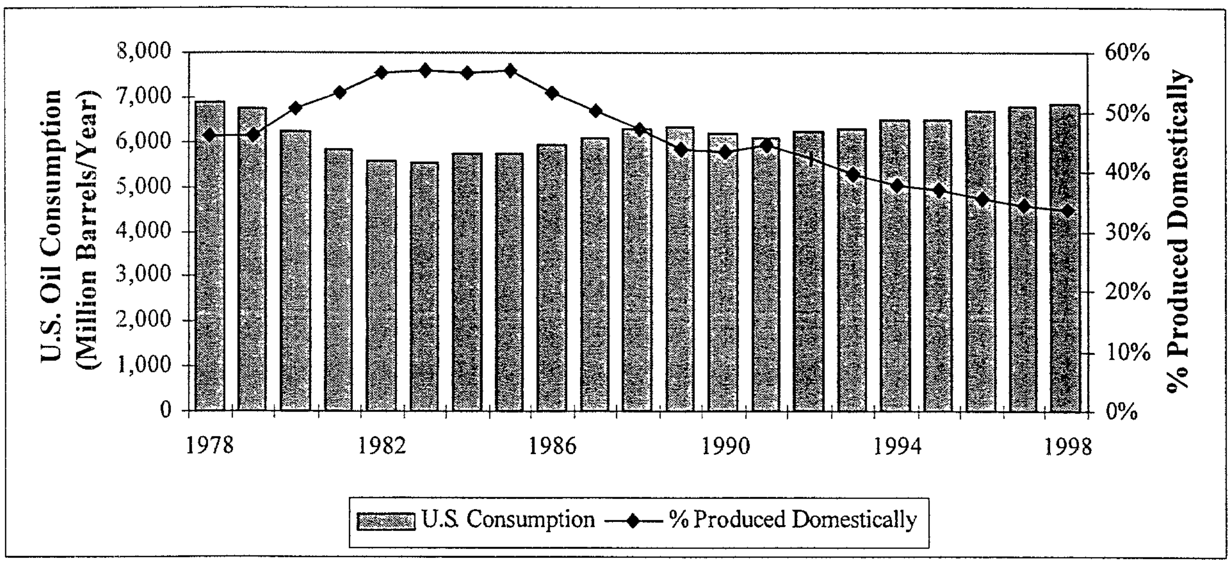
Another unique aspect of the industry is the marginal nature of many operations. Oil and gas wells can have very long lives (20 years or more); some wells drilled in the early years of this century are still producing, but only in small volumes. Wells typically have higher production in the early years, then decline and can level off at a low level of production that can be sustained for a long period (API, 1999). Wells that produce less than 10 barrels of oil per day are called "stripper wells." As of 1997, there were 436,000 active stripper wells (76 percent of all active domestic wells) producing an average of 2.2 barrels each daily. Together stripper wells account for about 15 percent of domestic production (IPAA, 1999).

II.B.3. Economic Trends

Domestic Consumption

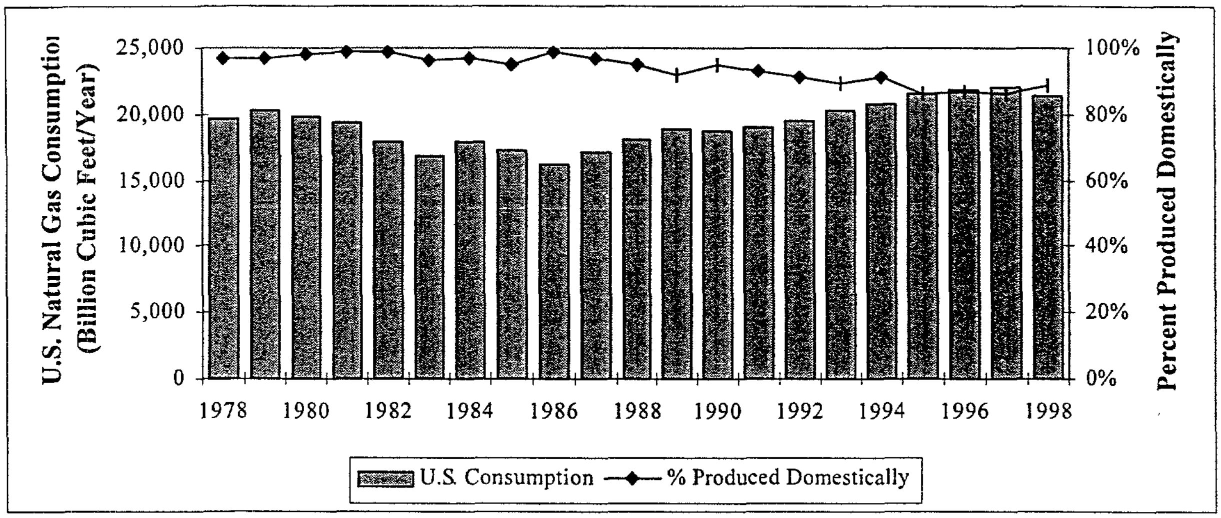
The consumption of oil and gas in the United States is closely linked to the overall economy of the country. Between 1990 and 1998, crude oil consumption increased approximately 1.4 percent each year, and natural gas consumption increased at a rate of 2.0 percent per year. The rate of natural gas consumption is expected to continue growing, mostly at the expense of coal. Natural gas is expected to become an important source of energy in the future and will be accelerated by government policies and the development of the natural gas transportation infrastructure. In the past several years, however, the percent of the domestic consumption of both oil and gas met by domestic producers generally has decreased (Figures 4 and 5).

Figure 4: U.S. Oil Consumption and Percent Produced Domestically



Source: EIA and IPAA, 1999.

Figure 5: U.S. Natural Gas Consumption and Percent Produced Domestically

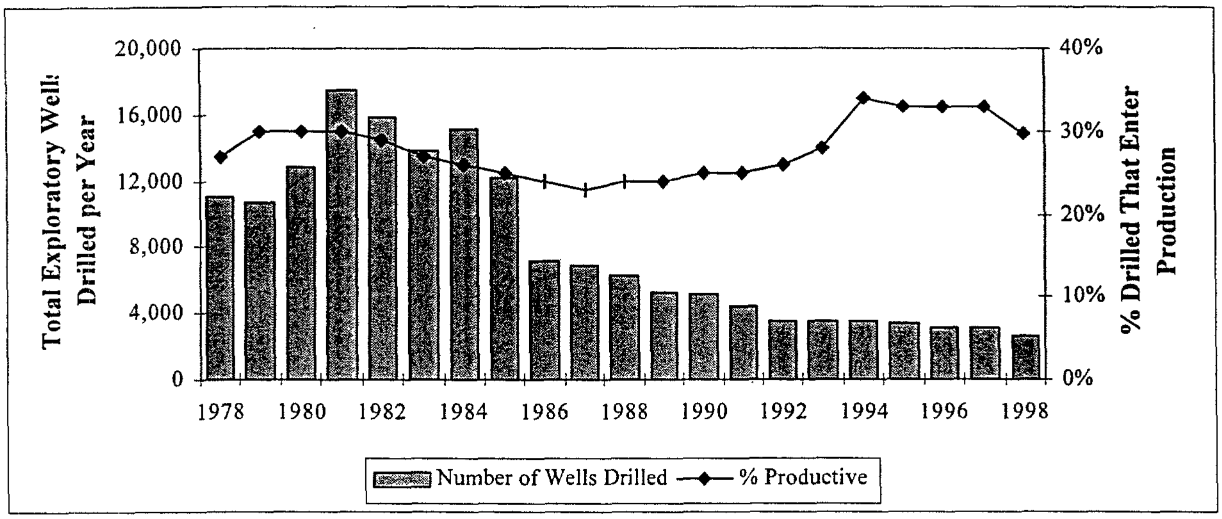


Source: EIA and IPAA, 1999.

Exploration and Reserves

The industry is exhibiting a general trend in exploration from domestic to foreign locations. In 1986, U.S. petroleum companies spent $17 billion on exploration and development within the United States and $7.5 billion abroad. In 1995, these firms spent $12.4 billion in the United States and $13.2 billion abroad (U.S. Department of Commerce (U.S. DOC), 1998). This shift in funds has placed an emphasis on drilling exploratory wells only at the most promising sites in the U.S. The results can be seen in Figure 6; many fewer exploratory wells are being drilled, but the success rate is higher.

Figure 6: Number of Exploratory Wells Drilled and Percent That Enter Production



Note: Includes both oil and natural gas wells.
Source: American Petroleum Institute, 1999.

The most active areas of exploration are the Gulf of Mexico and Alaska. In the Gulf of Mexico, the development of technology that facilitates drilling in deeper water (including floating structures, drillships and subsea completions) has made it more feasible to explore deep water sites. Another new source for potential reserves[2] is in Alaska, where roughly 87 percent of the Northeast National Petroleum Reserve was opened in 1998 for exploration and leasing (DOI, 1998). Developments such as these temporarily have boosted hydrocarbon reserves above production levels. In 1997, for the first time in a decade, crude oil reserves were added at a level greater than the amount depleted through production. However, it is expected that in the future reserves will again decline relative to production (EIA, 1998).

Natural gas exploration efforts in the United States have been more successful than crude oil exploration at keeping pace with production. Between 1994 and 1997, the industry added more reserves than it extracted in production. In 1997, about 64 percent of the new reserves of natural gas were found in the Gulf of Mexico Federal Offshore region and Texas (EIA, 1998).

Domestic Production and Prices

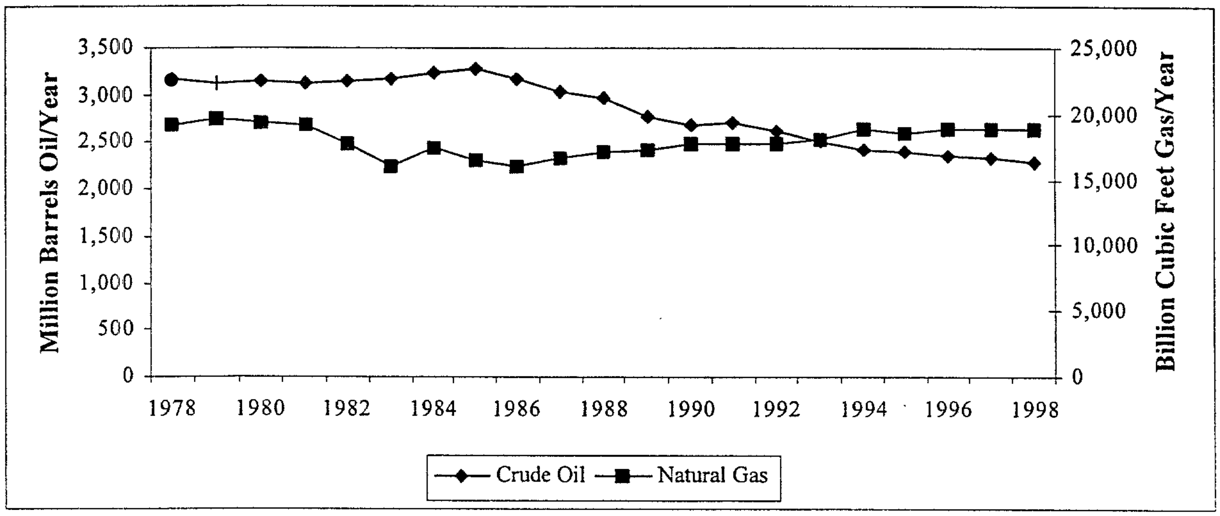
Production of crude oil is showing a decreasing trend, and natural gas production is showing an increasing trend. As shown in Figure 7, crude oil

[2] The Energy Information Administration of the U.S. Department of Energy defines proved reserves as those volumes of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions (EIA, 1998).

production is decreasing at an approximate rate of 1.5 percent per year. Leading the decline is Alaska, where production has declined approximately three percent per year in the past decade and six percent in 1997.

The production of natural gas, however, has been increasing steadily. Historically, growth has been about 1 percent per year, and is expected to grow at a rate of 1.6 percent per year through 2002 (U.S. DOC, 1998).

Figure 7: Domestic Crude Oil and Natural Gas Production

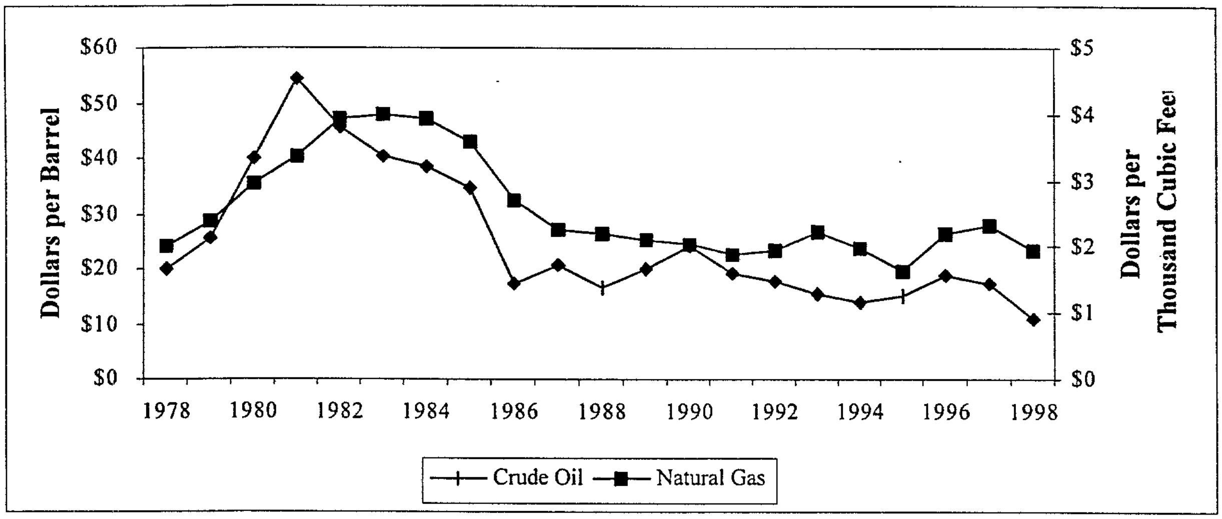


Source: EIA and IPAA, 1999.

As shown in Figure 8, the prices of both oil and gas have been quite volatile during the period between 1978 and 1997. In constant 1998 dollars, the wellhead price of crude oil has ranged between \$10 and \$54 per barrel. In 1998 and early 1999, prices were near \$10 per barrel, but by August 1999 the price rebounded to over \$20 per barrel (EIA, 1999).

Natural gas prices also have fluctuated. Wellhead prices reached a low point of \$1.62 per thousand cubic feet in 1995, but increased in the subsequent two years. Prices of natural gas are expected to increase faster than those of oil through 2002, but still less than the rate of inflation (U.S. DOC, 1998).

Figure 8: Wellhead Crude Oil and Natural Gas Prices, Fixed 1998 Dollars



Source: EIA and IPAA, 1999.

III. INDUSTRIAL PROCESS DESCRIPTION

This section describes the major industrial processes within the oil and gas extraction industry, including the materials and equipment used and the processes employed. Specifically, this section contains a description of commonly used drilling and production processes, associated raw materials, the byproducts produced or discharges released, and the materials either recycled or transferred off-site. This discussion also provides a concise description of both the production and the potential fate of wastes produced in each process.

The section is designed for those interested in gaining a general understanding of the industry, and for those interested in the inter-relationship between the industrial process and the topics described in subsequent sections concerning waste outputs, pollution prevention opportunities, and federal regulations. This section does not attempt to replicate published engineering information that is available for this industry. Refer to Section IX for a list of reference documents that are available to supplement this document.

III.A. Industrial Processes in the Oil and Gas Extraction Industry

The oil and gas extraction industry can be classified into four major processes: (1) exploration, (2) well development, (3) production, and (4) site abandonment. Exploration involves the search for rock formations associated with oil or natural gas deposits, and involves geophysical prospecting and/or exploratory drilling. Well development occurs after exploration has located an economically recoverable field, and involves the construction of one or more wells from the beginning (called *spudding*) to either abandonment if no hydrocarbons are found, or to well completion if hydrocarbons are found in sufficient quantities.

Production is the process of extracting the hydrocarbons and separating the mixture of liquid hydrocarbons, gas, water, and solids, removing the constituents that are non-saleable, and selling the liquid hydrocarbons and gas. Production sites often handle crude oil from more than one well. Oil is nearly always processed at a refinery; natural gas may be processed to remove impurities either in the field or at a natural gas processing plant.

Finally, site abandonment involves plugging the well(s) and restoring the site when a recently-drilled well lacks the potential to produce economic quantities of oil or gas, or when a production well is no longer economically viable.

Two ancillary processes are also discussed in this section because they have significant economic and environmental implications. Maintenance of the well and reservoir is important in sustaining the safety and productivity of the operation and in ensuring protection of the environment. Spill mitigation is important in the oil and gas production industry because spills and other types of accidents can have serious implications for worker safety and the environment.

III.A.1. Exploration

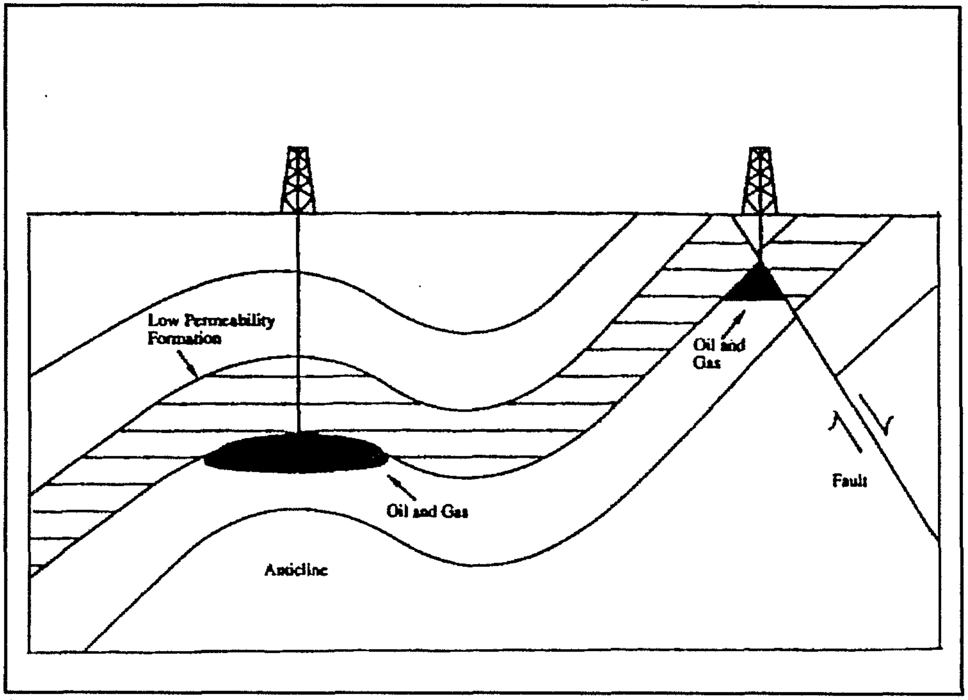
Oil and natural gas deposits are located almost exclusively in sedimentary rock and are often associated with certain geological structures. Geophysical exploration is the process of locating these structures in the subsurface via methods that fall under the category of remote sensing. In particular, common hydrocarbon-containing structures are those where a relatively porous rock has an overlying low-permeability rock that would trap the hydrocarbons (Berger and Anderson, 1992). Two common structural traps are found in Figure 9: anticlines are upward folds in the rock layers, while faults are fractures in the Earth's surface where layers are shifted.

Geophysicists search for these structures by taking advantage of the fact that seismic waves will travel through, bend, absorb, and reflect differently off of various layers of rock (Berger and Anderson, 1992). Geophysicists generate these seismic waves at the earth's surface, and measure the reflected seismic waves with a series of sensors known as geophones. Seismic waves can be generated by a variety of sources ranging from explosives that are detonated in holes drilled below the surface, to land vibroseis and marine airguns. Land vibroseis is typically used near populated areas and near sensitive environmental areas where detonations are not desirable. In the vibroseis process, trucks are used to drop a heavy weight on hard surfaces such as paved roads in order to create seismic waves.

In marine locations, explosives are less effective and have deleterious environmental impacts. In addition, vibroseis is impractical in water that is hundreds of feet deep. Seismic energy is therefore created by an airgun, a large device that can be emptied of air and water to create a vacuum. Seismic waves are created when water is allowed into the device at a very fast rate. It should be stressed that geophysical remote sensing cannot identify oil or gas accumulations directly; it can only indicate the potential for reserves via the presence or absence of certain rock characteristics that may be worthy of exploration.

After a site has been judged to have a reasonable chance of discovering a sufficient amount of hydrocarbons an exploratory well is drilled. It should be noted that although seismic exploration technology is constantly improving, it is not perfect. The only true way to discover the presence and quantity of petroleum is by drilling a well into the formation or structure suspected of containing hydrocarbons.

Figure 9: Common Oil and Gas Structural Traps



Source: EPA, 1992.

III.A.2. Well Development

Drilling

During the drilling process, wellsite geologists will augment the remote geophysical data with wireline logs, which are taken by means of devices lowered into the wellbore with wires. Wireline logs include several types of measurements that help to characterize the depths and thickness of subsurface formations and the type of fluids that they may contain. As an example, one type of log analyzes the resistance of the formation to electrical current, which helps to indicate the type of fluid and the porosity of the formation. For exploratory wells, mud logs may also be developed, which document the drill rate, types of rocks encountered, and any hydrocarbons encountered. The range of depths of well holes, or *wellbores,* is anywhere between 1,000 and 30,000 feet, with an average depth of all U.S. wells drilled in 1997 of 5,601 feet (API, 1998a).

For both onshore and offshore sites, the subterranean aspects of the drilling procedure are very similar. The drill bit is the component in direct contact with the rock at the bottom of the hole, and increases the depth of the hole by chipping off pieces of rock. The bit may be anywhere from three and three-fourths inches to two feet in diameter, and is usually studded with hardened steel or diamond. The selection of the drill bit can vary, depending on the type of rock and desired drilling speed. For example, a large-toothed steel bit may be used if the formation is soft and speed is important, while a diamond-studded bit may be used for hard formations or when a long drill life is desired (Kennedy, 1983). The drill bit is connected to the surface by several segments of hollow pipe, which together are called the *drill string*. The drill string is usually about 4 inches in diameter; drilling fluid is pumped down through its center and returns to the surface through the space, called the *annulus*, between the drill string and the rock formations or casing.

Drilling Fluids

Drilling fluid is an important component in the drilling process. A fluid is required in the wellbore to: (1) to cool and lubricate the drill bit; (2) remove the rock fragments, or *drill cuttings,* from the drilling area and transport them to the surface; (3) counterbalance formation pressure to prevent formation fluids (i.e. oil, gas, and water) from entering the well prematurely, and (4) prevent the open (uncased) wellbore from caving in (Berger and Anderson, 1992; Souders, 1998). Different properties may be required of the drilling fluid, depending upon the drilling conditions. For example, a higher-density fluid may be needed in high-pressure zones, and a more temperature-resistant fluid may be desired in high-temperature conditions. While drilling fluid may be a gas or foam, liquid-based fluids (called *drilling muds*) are used for approximately 93 percent of wells (API, 1997). In addition to liquid, drilling muds usually contain bentonite clay that increases the viscosity and alters the density of the fluid. Drilling mud may also contain additional additives that alter the properties of the fluid. The most significant additives are described later in this section. The American Petroleum Institute (API) environmental guidance document "Waste Management in Exploration and Production Operations," (API E5) considers the three general categories of drilling fluid (muds) to be water-based, oil-based, and synthetic-based. Synthetic-based muds are used as substitutes for oil-based muds, but also may be an advantageous replacement for water-based muds in some situations.

Water-based muds are used most frequently. The base may be either fresh or salt water, for onshore and offshore wells, respectively. The primary benefit of water-based muds is cost; they are the least expensive of the major types of drilling fluids, and in general they are less expensive to use since the resultant drilling waste can be discharged onsite provided these wastes pass regulatory requirements (EPA, 1999). The significant drawback with water-based muds is their limited lubricity and reactivity with some shales. In deep holes or high-angle directional drilling, water-based muds are not able to supply sufficient lubricity to avoid sticking of the drill pipe. Reactivity with clay shale can cause the destabilization of the wellbore. In these cases, oil-based and synthetic muds are needed.

In 1993 EPA estimated that about 15 percent of wells drilled deeper than 10,000 feet used some oil-based muds (USEPA, 1993b). Oil-based muds are composed primarily of diesel oil or mineral oil and are therefore more expensive than water-based muds. This higher cost, which includes the added burden of removing the oil from drill cuttings, and the required disposal options make oil-based muds a less frequently used option. Oil-based muds are well suited for the high temperature conditions found in deep wells because oil components have a higher boiling point than water, and oil-based muds can avoid the pore-clogging that may occur with water-based muds. Also oil-based muds are used when drilling through reactive (or high pressure) shales, high-angle directional drilling, and drilling in deep water. These situations encountered while drilling can slow down the drilling rate, increase drilling costs or even be impossible if water-based muds are used. In cases when oil-based muds are necessary, the upper section of a well generally is drilled with water-based muds and the conversion is made to oil-based mud when the situation requires it. It is predicted that since the industry trend is toward deeper wells, oil-based muds may become more prominent. However, because oil-based muds and their cuttings can not be discharged this may not be the case.

Since about 1990, the oil and gas extraction industry has developed many new oleaginous (oil-like) base materials from which to formulate high performance drilling fluids. A general class of these fluids are called synthetic materials, such as the vegetable esters, poly alpha olefins, internal olefins, linear alpha olefins, synthetic paraffins, ethers, linear alkylbenzenes, and others. Other oleaginous materials have also been developed for this purpose, such as enhanced mineral oils and non-synthetic paraffins. Industry developed synthetic-based fluids with these synthetic and non-synthetic oleaginous materials as the base fluid to provide the drilling performance characteristics of traditional oil-based fluids based on diesel and mineral oil, but with the potential for lower environmental impact and greater worker safety through lower toxicity, elimination of Polyaromatic hydrocarbons (PAH), faster biodegradability, lower bioaccumulation potential and in some drilling situations decreased drilling waste volume (FR 66086, December 16, 1996).

On land air and foam fluids may be used in drilling wells. These fluids are less viscous than drilling muds, and can enter smaller pores more easily. They are used when a higher rate of penetration into the formation is desired. Because air is less dense than a liquid, however, these fluids cannot exert the same pressure in the hole as liquid, and their viscosity can be altered if drilling encounters liquid in the formation. For this reason, air and foam fluids are used only in relatively low-pressure and water-free drilling locations, but are preferred in these situations because these fluids are much less expensive than other fluids (Kennedy, 1983; Souders, 1998). Air and foam fluids currently are used in the drilling of about seven percent of the wells in the United States (API, 1997).

Drilling muds typically have several additives. (Air and foam fluids typically do not contain many additives because the additives are either liquid or solid, and will not mix with air and foam drilling fluids.) The following is a list of the more significant additives:

- Weighting materials, primarily barite (barium sulfate), may be used to increase the density of the mud in order to equilibrate the pressure between the wellbore and formation when drilling through particularly pressurized zones. Hematite (Fe_2O_3) sometimes is used as a weighting agent in oil-based muds (Souders, 1998).

- Corrosion inhibitors such as iron oxide, aluminum bisulfate, zinc carbonate, and zinc chromate protect pipes and other metallic components from acidic compounds encountered in the formation.

- Dispersants, including iron lignosulfonates, break up solid clusters into small particles so they can be carried by the fluid.

- Flocculants, primarily acrylic polymers, cause suspended particles to group together so they can be removed from the fluid at the surface.

- Surfactants, like fatty acids and soaps, defoam and emulsify the mud.

- Biocides, typically organic amines, chlorophenols, or formaldehydes, kill bacteria that may produce toxic hydrogen sulfide gas.

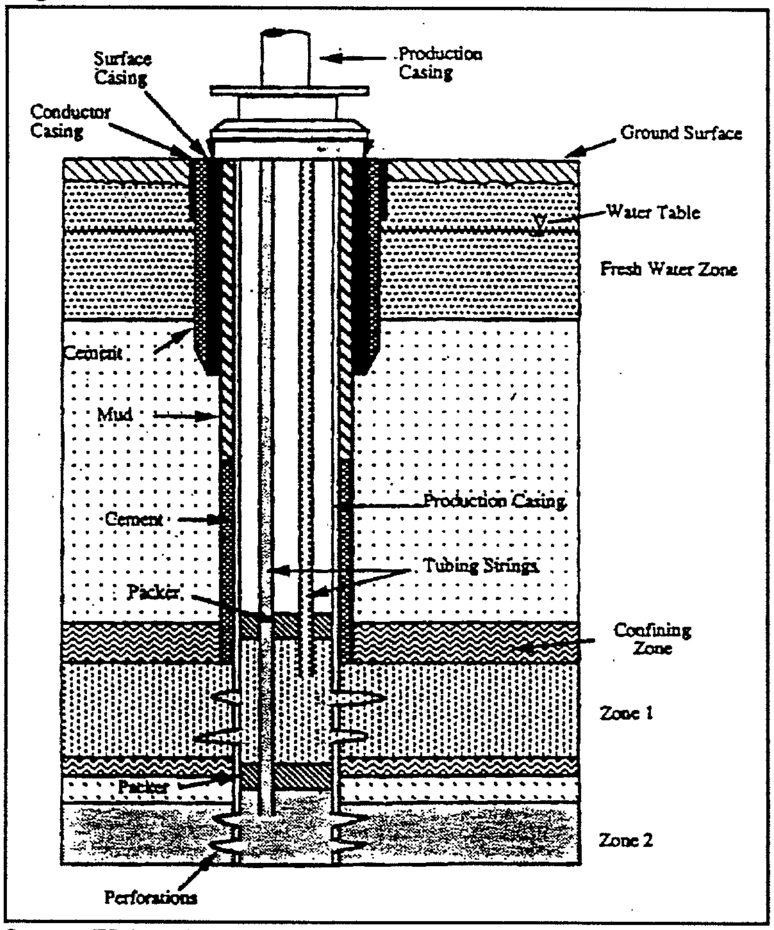
- Fluid loss reducers include starch and organic polymers and limit the loss of drilling mud to under-pressurized or high-permeability formations (EPA, Office of Solid Waste, 1987).

Casing

As the hole is drilled, casing is placed in the well to stabilize the hole and prevent caving. The casing also isolates water bearing and hydrocarbon bearing zones. As shown in Figure 10, three or four separate casing “strings” (lengths of tubing of a given diameter) may be used in intermediate-depth wells. In locations where surface soils may cave in during drilling, a "conductor" casing may be placed at the surface, extending only twenty to one hundred feet from the surface. This string is often placed prior to the commencement of drilling with a pile driver (Berger and Anderson, 1992). The next string, or "surface" casing, begins at the surface and may penetrate two thousand to three thousand feet. Its primary purpose is to protect the surrounding fresh-water aquifer(s) from the incursion of oil or brine from greater depths. The "intermediate" string begins at the surface and ends within a couple thousand feet of the bottom of the wellbore. This section prevents the hole from caving in and facilitates the movement of equipment used in the hole, e.g., drill strings and logging tools. The final "production" string extends the full length of the wellbore and encases the downhole production equipment. Shallow wells may have only two casing strings, and deeper wells may have multiple intermediate casings. After each casing string has been installed, cement is forced out through the bottom of the casing up the annulus to hold it in place and surface casing is cemented to the surface. Casing is cemented to prevent migration of fluids behind the casing and to prevent communication of higher pressure productive formations with lower pressure non-productive formations. Additional features and equipment shown in Figure 10 will be installed during the completion process for production: perforations will allow reservoir fluid to enter the wellbore; tubing strings will carry the fluid to the surface; and packers (removable plugs) may be installed to isolate producing zones.

Casing is important for both the drilling and production phases of operation, and must therefore be designed properly. It prevents natural gas, oil, and associated brine from leaking out into the surrounding fresh-water aquifer(s), limits sediment from entering the wellbore, and facilitates the movement of equipment up and down the hole. Several considerations are involved in planning the casing. First, the bottom of the wellbore must be large enough to accommodate any pumping equipment that will be needed either upon commencement of pumping, or in the later years of production. Also, unusually pressurized zones will require thicker casing in that immediate area. Any casing strings that must fit within this string must then be smaller, but must still accommodate the downhole equipment. Finally, the driller is encouraged to keep the hole size to a minimum; as size increases, so does cost and waste.

Figure 10: Cross Section of a Cased Well



Source: EPA, 1992.

Drilling Infrastructure

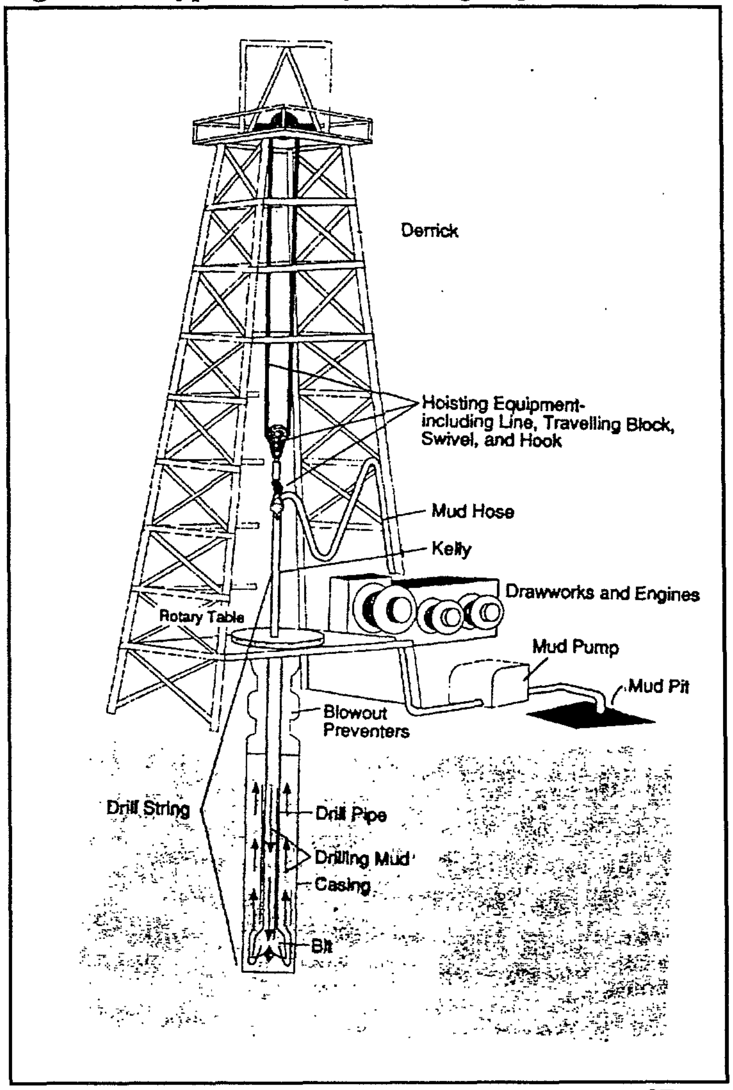
In addition to the well and its accouterments, infrastructure including construction and equipment is necessary at the surface. Roads and a pad are built at onshore sites; a ship, floating structure, or a fixed platform is needed for offshore operations. In addition, devices are needed to lift and lower the drilling equipment, filter rock cuttings from the drilling fluid, and store excess fluid and waste. The following sections describe the equipment required for onshore and offshore sites, respectively.

<u>Onshore Drilling</u>

Because the majority of onshore drilling sites are accessed by road, the equipment is geared toward mobility. First, an access road is built. In many locations the building of an access road is not difficult, but some areas present complications. On the North Slope of Alaska, for example, building a road that does not melt the permafrost can be both challenging and expensive. Board roads are used in some locations where soil conditions are not stable. Next, a footing for the equipment, usually gravel, is created in areas where the ground may be either unstable or subject to freeze/thaw cycles. Finally, the drilling rig is brought in. For shallow wells, the drill rig may be self-contained on a single truck; for deeper wells, the rig may be brought to the site in several pieces and assembled at the site.

A basic arrangement of the actual drilling equipment, or *rig*, is shown in Figure 11. The derrick (sometimes referred to as the mast) is the centerpiece of the operation, and is the frame from which the drill string is lifted, lowered, and turned. The hoisting equipment, kelly, and drill pipe connect the bit to the derrick. The drawworks and engines next to the derrick lift and drive the drill string, by turning the rotary table. The drilling mud is circulated through the wellbore via the mud hose (also called a gooseneck), down through the rotary hose (not shown), kelly, and drillpipe, out nozzles in the drill bit, and back up to the surface between the drill string and the wellbore. The mud is pumped by the mud pump, and is stored in the mud (or reserve) pit or in mud tanks. Finally, blowout preventers, which are described later in this section, are installed as a safety measure to prevent the drill pipe and subsurface fluids from being blown out of the hole if a high-pressure formation is encountered during drilling. Rigs will often have much more equipment, including a shale shaker which separates rock cuttings, a desander and desilter, which remove smaller particles, and a vacuum degasser, which removes entrained gas (Berger and Anderson, 1992).

Figure 11: Typical Rotary Drilling Rig



Source: Energy Information Administration, Department of Energy, 1991.

Offshore Drilling

For offshore sites, selecting the type of drilling rig needed is very important. Two primary considerations in rig selection are: (1) the size of the rig needed for the depth drilled, and (2) the depth of the water. Exploratory wells (called wildcat wells) may be located far from established oil and natural gas fields, and the rig must be transported over a significant distance. Mobility is therefore a primary concern in these situations. The depth of water at the drilling site is also important. If the water is fairly shallow, a ground-supported rig may be used. If the water is deep (typically over 400 feet), a floating rig may be necessary. The following is a description of the significant offshore rig types:

Drillships are a popular choice for drilling in deep water, because they are the most mobile of the rig types and have a large capacity for drill strings, casing, and similar supplies. A drillship has a standard ship hull, with the derrick extending from its center. The ship is kept in place by anchors or by dynamic positioning, a system in which propellers on each side of the ship are coordinated to keep the ship in the same location despite wind, currents, and the torsion caused by drill activities.

Semi-submersible drilling rigs are another option at deep water sites. The rig is usually a rectangular structure that holds the drilling equipment, with ballast containers underneath. These containers can be filled with air to float the rig when moving it. The rig is held in place by anchors or dynamic positioning. The semi-submersible rig is more stable than a drillship, but it is also more cumbersome to move from site to site.

Jack-up rigs float and are very mobile, but rest on the sea floor when drilling. For this reason, they are used in relatively shallow water (i.e., under 400 feet). The rig is towed into place floating, and legs, previously raised for transportation, are lowered to the ocean bottom so that the rig is raised above the water and supported on the ocean floor. The legs may be raised and lowered independently to compensate for an uneven sea floor. In an alternative footing method, mat support, the legs are attached to a mat on the sea floor; this mat distributes the weight over a larger area and minimizes the risk of the rig sinking into the soft ocean floor.

Fixed structures are commonly used after exploratory or developmental drilling prove a site has economically recoverable hydrocarbons. In these cases, offshore drilling rigs are mounted onto the production platform, which are securely pinned to the sea floor by concrete, steel, or tension legs. Tension legs are hollow steel tendons that allow no vertical movement, but some horizontal movement. They are the largest and most complex offshore structures and can be used in water in depths of over 500 feet (usually less than 1,000 feet). Platforms are very stable and can withstand waves greater than 60 feet high, and winds in excess of 90 knots. Assembling a fixed platform is a sizeable investment; some platforms have been reported to cost over $1 billion (Berger and Anderson, 1992). For this reason, multiple wells are usually drilled at outward angles from a single platform. The centralizing of pumps and separation equipment also make this a convenient arrangement for production (Kennedy, 1983).

Lake and Wetland Drilling

Inland regions of water often require additional engineering techniques and special adaptations other than the onshore and offshore practices mentioned above. In places of deeper and more open water, barge rigs may be used for drilling. In shallow areas or wetlands, stationary rigs can be constructed or the area can be backfilled and drilled with a land-based rig. Canals may also be dredged to bring in floating or submergible drilling rigs. It is common while drilling in wetlands to use the directional drilling technique in order to disrupt as little of the wetland as possible while developing a field. Often supplies and equipment must be transported by helicopter, or dredging is required for access by barge rigs. Regardless of the approach used, these areas often pose challenges for erecting the rig and transporting materials and personnel to and from the site, and involves compliance with Clean Water Act wetlands regulations (See Section VI.B for additional information) (Kennedy, 1983, and EPA, 1995).

Well Completion

When drilling has been completed, several steps may be needed before production begins. First, testing is performed to verify whether the hydrocarbon-bearing formations are capable of producing enough hydrocarbons to warrant well completion and production. As many as three types of tests may be performed before the final (production) string of casing is installed. These tests are coring, wireline logging, and drill stem testing.

Coring is typically performed only in exploratory wells, and not in fields where several wells have already been drilled. A special drill removes an intact sample, or *core*, of rock at the depth where oil or gas is most likely to be. The core can be as short as 15 feet or as long as 90 feet. Special side-wall coring techniques may be employed in some wells. Unlike the more indirect testing methods described below, a core allows a geologist to observe the rock type directly, and measure its *porosity*, or the volume of fluid-occupying space relative to the volume of rock, and *permeability*, the ease with which fluids can flow through a porous rock.

Wireline logging refers to the recording of acoustical, electrical resistivity, and other geophysical measurements within a wellbore. These measurements provide detailed information on the geologic formations encountered by the well, and augment the seismic data recorded prior to the well drilling and the mud log for that well. These data often help to determine more precisely the depth at which oil and gas could be produced. A logging of electrical resistivity takes advantage of the fact that some compounds are better insulators of electrical charge than others. For example, oil, gas, and consolidated rock resist electrical current better than water and unconsolidated rock. Additional tests may be used; radioactivity logs can differentiate between types of rock, and neutron logs can measure the amount of liquid in the formation (but not differentiate between oil and water). Logging is performed on nearly all wells, and multiple forms of logging may be used in conjunction with each other to attain a more complete analysis. For example, a neutron log will indicate the amount of liquid in a formation, and a resistivity log may help to determine what percentage of that liquid is oil. Certain types of logs may be conducted during drilling with a special tool located on the drillstring above the bit.

Drill stem testing may be the most important and definitive test. Equipment attached to the bottom of a drill string traps a sample of formation fluid. Measuring the pressure at which the fluid enters the chamber and the pressure required to expel that fluid back into the formation yields an estimate of the flow rate of formation fluid to be expected during production. If the flow rate is expected to be too low, procedures such as stimulation (see below) may be required to increase the flow before production equipment is installed.

<u>Perforation</u>
When the production casing is cemented in the wellbore, the casing is sealed between the casing and the walls of the well. For formation fluid (oil, gas, and water) to enter the well, the casing must be perforated. The depth of the producing zone is determined by analyzing the logging data; small, directed explosive charges are detonated at this depth, thereby perforating the casing, cement, and formation. The result is that formation fluid enters the well, yet the rest of the well's casing remains intact.

<u>Stimulation</u>
Some formations may have a large amount of oil as indicated by coring and logging, but may have a poor flow rate. This may be because the production zone is not have sufficient permeability, or because the formation was damaged or clogged during drilling operations. In these cases, pores are opened in the formation to allow fluid to flow more easily into the well. The hydraulic fracturing method involves introducing liquid at high pressure into the formation, thereby causing the formation to crack. Sand or a similar porous substance is then emplaced into the cracks to prop the fractures open. Another method, acidizing, involves pumping acid, most frequently hydrochloric acid, to the formation, which dissolves soluble material so that pores open and fluid flows more quickly into the well. Both fracturing and acidizing may be performed simultaneously if desired, in an acid fracture treatment. Stimulation may be performed during well completion, or later during maintenance, or *workover*, operations, if the oil-carrying channels become clogged with time (EPA, 1992).

<u>Production equipment installation</u>
When drilling, casing, and testing operations are completed, the drilling rig is removed and the production rig is installed. In most cases, tubing is installed in the well which carries the liquids and gas to the surface. At the surface, a series of valves, collectively called the Christmas tree because of its appearance, is installed to control the flow of fluid from the well. Pumps are

added if the formation pressure is not sufficient to force the formation fluid to the surface. Different types of pumps are available; the most common is the rod pump. The rod pump is suspended on a string of rods from a pumping unit, and the prime mover for pumping units can be an electric motor, or a gas engine. Equipment is usually installed onsite to separate natural gas and liquid phases of the production and remove impurities. Finally, a pipeline connection or storage container (tank) is connected to the well to facilitate transport or store the product. In the case of natural gas, which cannot be stored easily, a pipeline connection is necessary before the well can be placed on production.

Although the practice is becoming less common, one or more pits may be constructed for onshore facilities. These may include a skimming pit, which reclaims residual oil removed with water that has been removed from the product stream; a sediment pit, which stores solids that have settled out in storage tanks; or an evaporation or percolation pit, which disposes of produced water (EPA, 1992).

III.A.3. Petroleum Production

The major activities of petroleum production are bringing the fluid to the surface, separating the liquid and gas components, and removing impurities. Frequently, oil and natural gas are produced from the same reservoir. As wells deplete the reservoirs into which they are drilled, the gas to oil ratio increases (as well as the ratio of water to hydrocarbons). This increase of gas over oil occurs because natural gas usually is in the top of the oil formation, while the well usually is drilled into the bottom portion to recover most of the liquid. Although the following discussion is geared toward wells producing both oil and gas, the majority of the discussion also applies to wells producing exclusively one or the other.

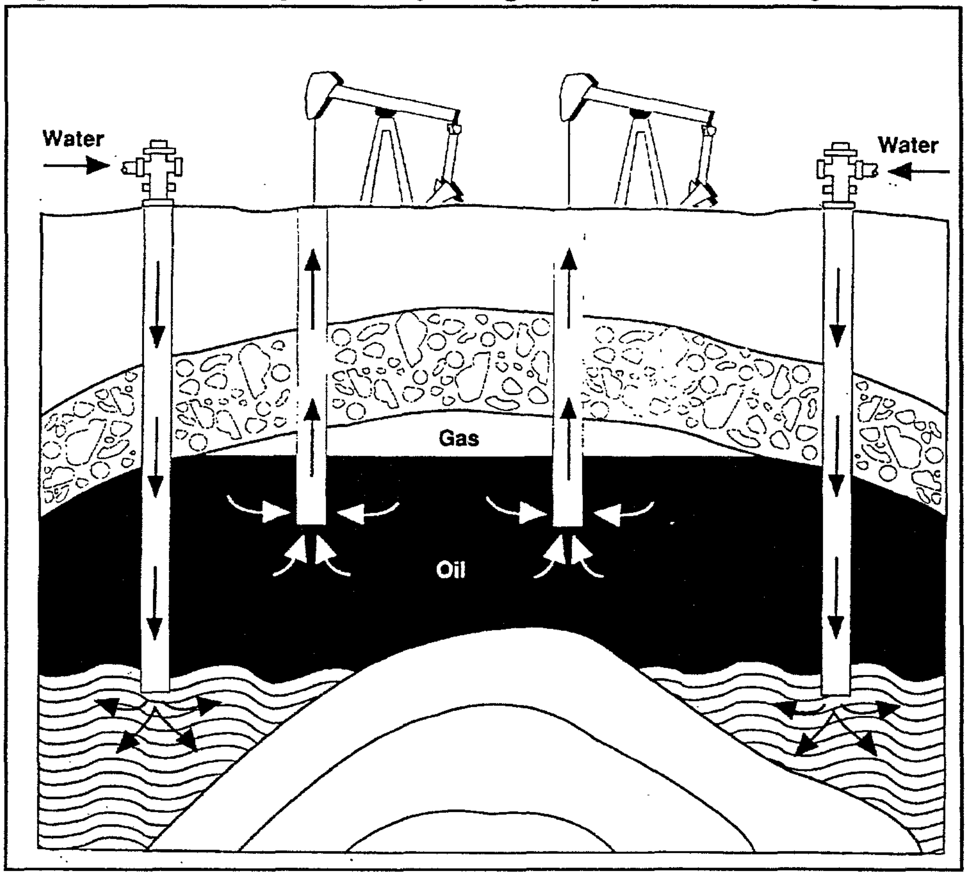
Primary Production

Primary recovery is the first stage of hydrocarbon production, and natural reservoir pressure is often used to recover oil. When natural pressure is not sufficiently capable of forcing oil to the surface, artificial lift equipment is then employed. This includes various types of pumps, gas lift valves, and may occasionally include oil stimulation. When pumping is employed, motors may be used at the surface or inside the wellbore to assist in lifting the fluid to the surface. Primary production accounts for less than 25 percent of the original oil in place.

Secondary Recovery

Secondary recovery enhances the recovery of liquid hydrocarbons by repressurizing the reservoir and reestablishing or supporting the natural water drive. Usually water which is produced with the oil is reinjected, but other sources of water may also be used. This type of secondary recovery is generally called a "waterflood" (See Figure 12). Produced water injection for enhanced recovery of crude oil and natural gas is recognized as a form of recycling of this waste. Furthermore, produced water is more commonly injected for the purpose of secondary recovery than in an injection well that is only used for disposal (in Texas, approximately 61 percent of injected produced water is for enhanced recovery) (Texas Railroad Commission, 1999). This procedure is described further in Section III.C., Management of Wastestreams. Gas is injected to enhance gas cap drive in some reservoirs.

Figure 12: Secondary Recovery Using Pumps and Water Injection



Source: Energy Information Administration, Department of Energy, 1991.

Tertiary Recovery

A final method for removing the last extractable oil and gas is tertiary recovery. In contrast to primary and secondary recovery techniques, tertiary recovery involves the addition of materials not normally found in the reservoir (Lake, 1989). These methods are often expensive and energy-intensive (Sittig, 1978). In most cases, a substance is injected into the reservoir, mobilizes the oil or gas, and is removed with the product. Examples include:

- Thermal recovery, in which the reservoir fluid is heated either with the injection of steam or by controlled burning in the reservoir, which makes the fluid less viscous and more conducive to flow;
- Miscible injection, in which an oil-miscible fluid, such as carbon dioxide or an alcohol, is injected to reduce the oil density and cause it to rise to the surface more easily;
- Surfactants, which essentially wash the oil from the reservoir; and
- Microbial enhanced recovery, in which special organic-digesting microbes are injected along with oxygen into the formation to digest heavy oil and asphalt, thereby allowing lighter oil to flow (Lake, 1989; EPA, 1992)

Crude Oil Separation

When the formation fluid is brought to the surface, it may contain a spectrum of substances including natural gas, water, sand, silt, and any additives used to enhance extraction. The general order of separation with respect to oil is the following: the separation of gaseous components, the removal of solids and water, and the breaking up of oil-water emulsions. (The conditioning of the natural gas that is removed in the first step will be discussed in the next subsection.)

The removal of gaseous components primarily is intended to remove natural gas from the liquid; however, gaseous contaminants such as hydrogen sulfide (H_2S) also may be produced in some fields during this process. The gases are removed by passing the pressurized fluid through one or two decreasing pressure chambers; less and less gas will remain dissolved in the solution as the pressure is lowered.

The liquids and solids that remain are usually a complex mix of water, oil, and sand. Water and oil are generally immiscible; however, the extraction process is usually very turbulent and may cause the water and oil to form an emulsion, in which the oil forms tiny droplets in the water (or vice versa). Fluid separation often produces a layer of sand, a layer of relatively oil-free water, a layer of emulsion, and a (small) layer of relatively pure oil. The free water and sand, or basic sediment and water (BS&W) are generally removed by a process called free water knockout, in which the BS&W are removed primarily by gravity. Finally, emulsions are broken by heating the fluid in a heater-treater to a temperature of 100-160 degrees fahrenheit, or by treating it with emulsion-breaking chemicals (Arnold and Stewart, 1998). Following the emulsion breaking, the oil is about 98 percent pure, which is sufficient for storage or transportation to the refinery (Sittig, 1978).

Natural Gas Conditioning

Natural gas conditioning is the process of removing impurities from the gas stream so that it is of high enough quality to pass through transportation systems. It should be noted that conditioning is not always required; natural gas from some formations emerges from the well sufficiently pure that it can pass directly to the pipeline. As the natural gas is separated from the liquid components, it may contain impurities that pose potential hazards or problems. The most significant is hydrogen sulfide (H_2S), which may or may not be contained in natural gas. Hydrogen sulfide is toxic (and potentially fatal at certain concentrations) to humans and corrosive for pipes; it is therefore desirable to remove it as soon as possible in the conditioning process. Another concern is that posed by water vapor. At high pressures, water can react with components in the gas to form gas hydrates, which are solids that can clog pipes, valves, and gauges (Manning and Thompson, 1991). Nitrogen and other gases may also be mixed with the natural gas (methane) in the subsurface. These other gases must be separated from the methane prior to sale. At cold temperatures the water can freeze, also clogging pipes, valves, and gauges. High vapor pressure hydrocarbons that are found to be liquids at surface temperature and pressure (benzene, toluene, ethylbenzene, and xylene, or BTEX) are removed and processed separately. Two significant natural gas conditioning processes are dehydration and sweetening.

Dehydration is performed to remove water from the gas stream. Three main approaches toward dehydration are the use of a liquid or solid desiccant, and refrigeration. When using a liquid desiccant, the gas is exposed to a glycol that absorbs the water. The water can be evaporated from the glycol by a process called heat regeneration, and the glycol can then be reused. Solid desiccants, often materials called molecular sieves, are crystals with high surface areas that attract the water molecules. The solids can be regenerated simply by heating them above the boiling point of water. Finally, particularly for gas extracted from deep, hot wells, simply cooling the gas to a temperature below the condensation point of water can remove enough water to transport the gas. Of the three approaches mentioned above, glycol dehydration is the most common when processing occurs in the field (at or near the well). At natural gas plants, solid desiccants are most commonly used (Smith, 1999).

Sweetening is the procedure in which H_2S and sometimes CO_2 are removed from the gas stream. The most common method is amine treatment. In this process, the gas stream is exposed to an amine solution, which will react with the H_2S and separate them from the natural gas. The contaminant gas solution is then heated, thereby separating the gases and regenerating the amine. The sulfur gas may be disposed of by flaring, incinerating, or when a market exists, sending it to a sulfur-recovery facility to generate elemental sulfur as a salable product. Another method of sweetening involves the use of iron sponge, which reacts with H_2S to form iron sulfide and later is oxidized, then buried or incinerated (EPA, 1992).

III.A.4. Maintenance

Production wells periodically require significant maintenance sessions, called *workovers*. During a workover, several tasks may be undertaken: repairing leaks in the casing or tubing, replacing motors or other downhole equipment, stimulating the well, perforating a different section of casing to produce from a different formation in the well, and painting and cleaning the equipment. The procedure often requires bringing in a rig for the downhole work. This rig can be smaller than those used for initially drilling a well.

Two procedures performed to improve the flow of fluid during workovers are removing accumulated salts (called *scale*) and paraffin, and treating production tubing, gathering lines, and valves for corrosion with corrosion-prevention compounds. As fluids are withdrawn from the formation, the salts that are dissolved in the produced water precipitate out of solution as the solution approaches the surface and cools. The resulting scale buildup can significantly reduce the flow of fluid through the tubing, gathering lines, and valves. Examples of scale removal chemicals are hydrochloric and hydrofluoric acids, organic acids, and phosphates (EPA, 1994). These solvents are added to the bottom of the wellbore and pumped through the tubing through which extracted fluid passes. In a similar fashion, corrosion inhibitors may be passed through the system to mitigate and prevent the effects of acidic components of the formation fluid, such as H_2S and CO_2. These corrosion inhibitors, such as ammonium bisulfite or several forms of zinc, may serve to neutralize acid or form a corrosion-resistant coating along the production tubing and gathering lines. Corrosion control activities can be continuous, not just at workover.

III.A.5. Well Shut-in/Well Abandonment

Production may be stopped for several reasons. If it is a temporary stoppage, the well is shut-in. If the closure is to be permanent, the well is either converted to a UIC Class II injection well, or it is plugged and abandoned.

A temporary shut-in is an option when the conditions causing the interruption in production are anticipated to be short-term. Examples include situations when the well may be awaiting a workover crew or a connection to a pipeline, or there may be a (temporary) lack of a market (Williams and Meyers, 1997). A well is shut in by closing the valves on the Christmas tree. Depending on the duration, the stoppage may be called a temporary abandonment, and regulatory approval and testing, including a mechanical integrity test (MIT), may be required in order to be idle (IOGCC, 1996). It is much more desirable to shut-in a well rather than plug it if production is still viable, because once the well is permanently plugged and abandoned, it is highly impractical to re-access the remaining oil in the reservoir.

If the well is part of a production field with many nearby wells still in production, the well may be converted to a UIC Class II injection well, which is regulated under the Safe Drinking Water Act (see Section VI.B, Sector-Specific Requirements for more information). Such a well can be used either for disposal of the produced water from these other wells, or may be part of a coordinated Enhanced Oil Recovery (EOR) effort in the field.

The final option is to plug and abandon the well. The goal of this procedure is to prevent fluid migration within the wellbore, which could contaminate aquifers or surface water. Oil and gas producing states all have specific regulations governing the plugging and abandonment of wells (see Section VI.B.4., State Regulations). When a well is plugged, the downhole equipment is removed and the perforated parts of the wellbore are cleaned of fill, scale and other debris. A minimum of three cement plugs are then placed, each of which are 100 to 200 feet long. The first is pumped into the perforated (production) zone of the well, in order to prevent the inflow of fluid. A second is placed in the middle of the wellbore. A third plug is placed within a couple hundred feet of the surface. Additional plugs may be placed anywhere within the wellbore when necessary. Fluid with an appropriate density is placed between the cement plugs in order to maintain adequate pressure. During this process, the plugs are tested to verify plug placement and integrity (Fields and Martin, 1998). Finally, the casing is cut off below the surface, capped with a steel plate welded to the casing, and at onshore sites, surface reclamation is undertaken to restore natural soil consistency and plant cover (EPA, 1992).

Problems are sometimes encountered with wells that have stopped production, yet neither have government approval nor have been plugged. These are generally called idle wells, or when the owners are not known or are insolvent, are called orphan wells. Please see Section III.B for the possible environmental impacts of such wells.

Offshore Platform Decommissioning

For offshore, the structure itself must be decommissioned in addition to plugging the well. Several options exist:

- Complete removal of the structure and disposing of the structure onshore
- Removing the structure and placing it in an approved location in the ocean
- Reuse of the structure elsewhere (National Research Council, 1996).

The method used will vary with the type of structure and water depth, but the most common approach is the complete removal of the structure, with removal at a minimum of 15 feet below the mudline (seafloor). Other approaches are less expensive and less intrusive to the existing environment, but can be more dangerous for commercial ships, military submarines, fishing trawlers, and recreational boaters. In Texas and Louisiana, however, it may be possible to participate in the states' "rigs-to-reefs" programs, which under the National Fishing Enhancement Act of 1984 seek to convert offshore structures to permanent artificial reefs (MMS, 1999).

When removing the structure, the most common approach is to sever the leg piles with explosives. Explosives must be placed at least five feet below the mud line (sea floor). Explosives are less expensive and are less risky to divers than alternatives such as manual or mechanical cutting, but concern has been raised about the use of explosives and their effect on marine life (National Research Council, 1996).

III.A.6. Spill and Blowout Mitigation

Accidental releases at oil and gas production facilities may come in two forms: spills or blowouts. Oil spills (usually consisting of crude oil or condensate) may come from several sources at production sites (and in some cases at drilling sites): leaking tanks, during transfers, or from leaking flowlines, valves, joints, or gauges. Other spills of oil have occurred such as diesel from drilling operations, oily drilling muds while being offloaded, and production chemicals (MMS, 1998). Spills are the most common type of accident and are often small in quantity.

Well blowouts are rare, but can be quite serious. They are most likely to occur during drilling and workovers, but can occur during any phase of well development including production operations. When the drill encounters an unusually pressurized zone or when equipment is being removed from the hole, the pressure exerted by the formation may become considerably higher than that exerted by the drilling or workover fluid. When this happens, the formation fluid and drilling or workover fluid may rise uncontrollably through the well to the surface. Downhole equipment may also be thrust to the surface. Especially if there is a significant quantity of associated natural gas, the fluid may ignite from an engine spark or other source of flame. Blowouts have been known to completely destroy rigs and kill nearby workers. Some blowouts can be controlled in a matter of days, but some -- particularly offshore -- may take months to cap and control (Kennedy, 1983).

Drilled wells and many workover wells are equipped with a blowout preventer. These blowout preventers (BOPs) are hydraulically operated, and serve to close off the drill pipe. BOPs can be operated manually, or can be automatically triggered. Most rigs have regular blowout drills and training sessions so that workers can operate the BOPs and escape as safely as possible.

Should a spill occur despite precautions, established responses should be undertaken. If the facility is subject to Spill Prevention Control and Countermeasure (SPCC) regulation (see Section VI.B for additional information), the facility will be equipped with secondary containment and diversionary structures to prevent the spill from reaching drains, ditches, rivers, and navigable waters. These structures may be berms, retention ponds, absorbent material, weirs, booms, or other barriers or equivalent preventive systems. Should these secondary containment devices not be adequate, the response will be different for onshore and offshore spills (EPA, 1999). In both cases, the goals are to stop the flow of oil, recover as much as possible of the material as a salable product, then minimize the impact on navigable waterways or groundwater.

Onshore Spills

For onshore spills, concern is for both surface runoff to streams, and for seepage into groundwater. The first considerations are to stop the source of the leakage and to contain the spill. Containment may either be achieved with pre-existing structures, or by using bulldozers at the time of response (Blaikley, 1979). Pooled oil would then be collected, pumped out, and whenever possible, processed for sale. When treating the contaminated soil, the remediation approach taken may vary considerably depending on the porosity of the soil and composition of the spilled fluid. If the spill has permeated less than about 6-10 inches of soil, bioremediation may be the most appropriate approach. With bioremediation, hydrocarbon-digesting microbes found naturally in soil are enhanced with fertilizers and moisture to degrade the material. The site would be tilled periodically and watered to maintain proper amounts of air and moisture. Should the temperature at the site be too cold or should the spill be too deep for bioremediation to be fully effective, approaches such as composting, or soil excavation with landspreading or landfilling, may be used either exclusively or in combination (Deuel and Holliday, 1997). Another option in remote locations or in situations when other options have not been successful is in-situ burning. In these situations, primarily when there is little surrounding vegetation, calm winds, and difficulty in transporting the equipment required for other methods, the oil is concentrated as much as possible and ignited by any of a variety of methods (Zengel, et al., 1998; Fingas, 1998). Application of in situ burning is still being refined.

Offshore Spills

The conditions for an offshore spill cleanup can vary substantially; from deep-water to coastal, from calm water to very choppy seas. As with onshore spills, initial priorities are to contain spilled oil and prevent further leakage. The oil is usually contained by booms, or floating devices that block the movement of surface oil. The booms may then be moved to concentrate the oil, at which point skimmers collect the oil. Booms may also be placed along a shoreline to minimize the amount of oil that reaches shore. For the oil that cannot be collected in this fashion, other approaches are used to minimize environmental impact, including sorbents, dispersants, or oil-digesting bacteria (EPA, 1993). In-situ burning also may be an option for offshore spills. This option may be best suited to arctic conditions, where cold temperatures keep the oil relatively concentrated and where ice may hinder the use of other methods. Depending on the thickness of the oil, the calmness of the seas, and other factors, the destruction rate can be over 90 percent (Fingas, 1998; Buist, 1998). This technique has not been widely used and is still considered experimental.